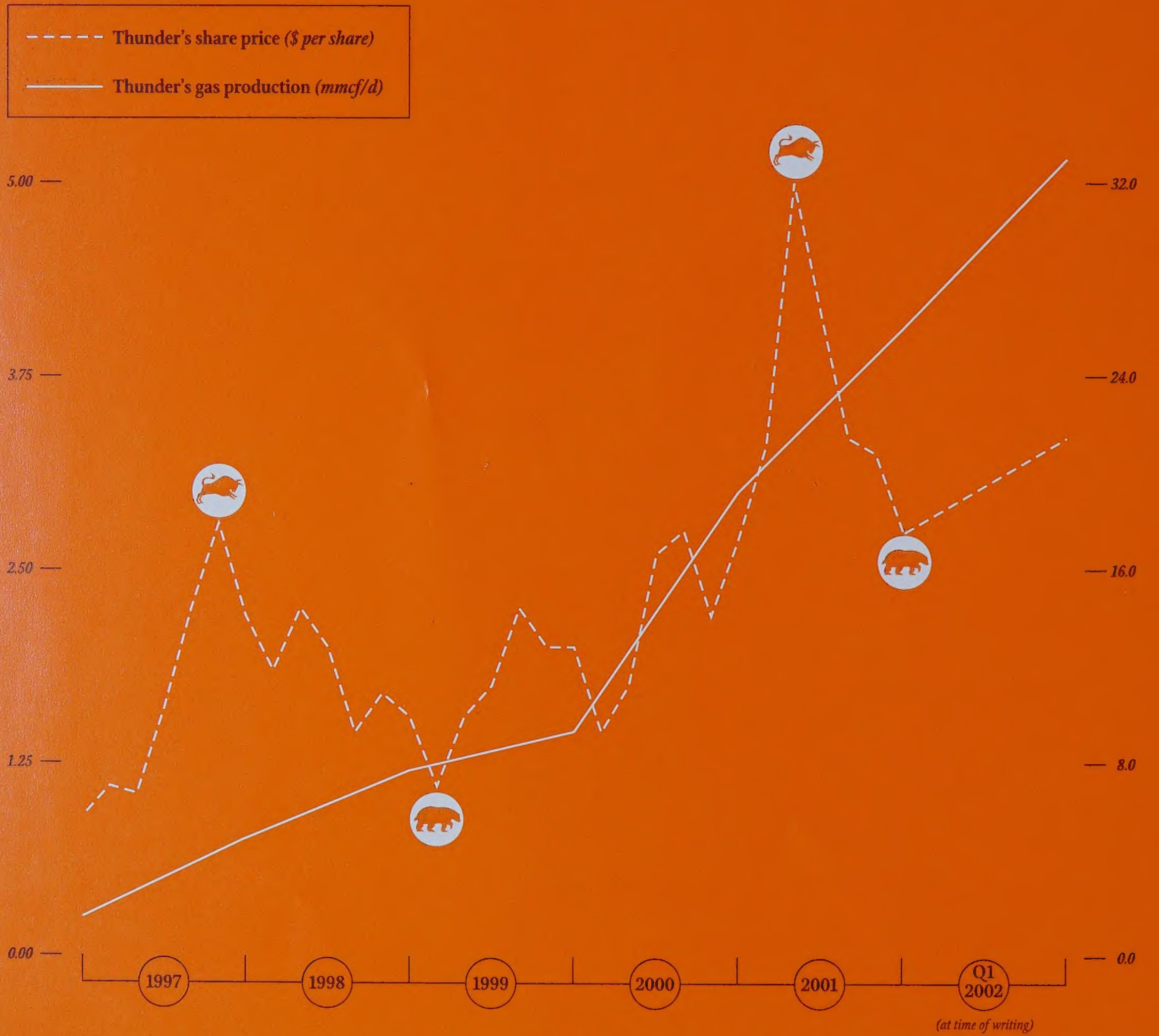
BULL OR BEAR

We know how to drive profit

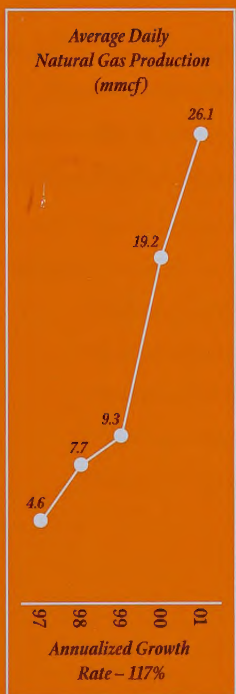
THUNDER ENERGY INC. 2001

www.thunderenergy.com



SEPARATE THE MARKET VOLATILITY FROM THE BUSINESS VIABILITY

HOW **Thunder** HAS GROWN. OUR SUCCESS HAS HINGED ON THE STRENGTH OF OUR TECHNICAL TEAM AND AN ABILITY TO MANAGE OUR BUSINESS THROUGH COMMODITY PRICE CYCLES.



A complete 5-year summary can be found on page 40. All boe volumes are reported at 6 mcf = 1 bbl.

1996 – 2001

Building a profitable company

Our track record of growth – and profitability – has given us a good deal of confidence in the way we run our business. Since our inception six years ago, our high rate of drilling success along with strategic acquisitions have built a base of stable production and a platform for growth, currently 80% weighted to natural gas. When a bear gas market is on the prowl, we work hard to high grade and add to our large inventory of drilling prospects. When a bull market turns the corner, we ramp up drilling and quickly bring new wells onstream. This strategy has been important in driving our profitability. Our business plan and operating strategies include:

- Operate core areas where we can add gas-weighted production and reserves
- Continually expand our land in core areas to maintain a dominant position
- Concentrate on drilling low to medium risk, multi-zone plays
- Bring wells onstream in less than 50 days
- Expand into areas that fit our operational criteria

Our asset base holds great gas potential

2002 AND BEYOND

THE PAYOFF WILL BE OUR GAS FOCUS

There is no doubt in our minds that natural gas is the place to be in the North American energy market. In 2001, natural gas prices peaked to an all-time high of $12.00/mcf only to nosedive to $2.50/mcf nine months later. In 2002, natural gas has rallied again moving from $2.95 to a current spot price of $4.75/mcf. This volatility is a sure sign of major concerns about a shortage of supply.

In the overall supply/demand equation, last year's price high came at a time when drilling activity was rising, gas supply was increasing – and demand was moving down as the US economy headed into recession. The exact opposite is now occurring – the US economy is gaining strength, while both North American drilling and production are decreasing. With supply concerns dominating the markets, our short-term strategy is to:

- Maximize gas production volumes prior to the winter heating season
- Mobilize additional drilling locations from our +125 gas prospect inventory in readiness for a sustained price rise
- Focus on central Alberta where low risk gas drilling has proven to add substantial reserves
- Target high reward, exploration wells at Rycroft in the Peace River Arch
- Remain unhedged as gas prices have already risen sharply

WE WILL RAMP UP DRILLING IF GAS PRICES CONTINUE TO RALLY

Corporate

- **Natural gas prices have begun to rally.**
- **125 gas locations are drill-ready.**
- **Q1 natural gas production is 40% higher than Q1 2000.**

President's Message

We see great potential in natural gas; in fact, it could become the most profitable commodity in the North American energy market. For the first time ever, the industry in both Canada and the US must drill a significant number of gas wells just to maintain current levels of production.

Concerns about a supply shortage were behind the January 2001 price spike to an all-time high of $12.00/mcf. Demand fell as many industrial users switched to less costly fuels, and then declined further with the US economic slowdown, which forced the price to a low of $2.50/mcf in September. We see more supply shortages and higher prices ahead:

- *Drilling activity peaked in the summer of 2001, but has declined steadily. In only six months, North American production has dropped an estimated 2 to 4 bcf/d.*
- *If drilling activity remains low, that decline will be more severe, increasing the possibility of another supply shortage.*
- *Demand requirements are rising with the improving US economy and fuel-switchers are back using natural gas.*

The natural gas market is still susceptible to supply shocks – and rising prices. Natural gas has the potential to generate huge returns for producers, such as we saw in the winter of 2000-2001. Thunder is in an ideal position to benefit if a supply shortage occurs, and our business strategy has the built-in flexibility to respond to changing markets.

Gas Prices are Rising

Gas prices are beginning to rally, having risen from $3.00/mcf in February 2002 to $4.75/mcf in late March. We believe that the market has passed through a low point in the commodity price cycle and, once again, concerns about supply shortages will drive a bull market. Price volatility will continue, but we foresee a solid recovery before next winter.

With our 80% weighting to natural gas, the recent price increase is having a major impact on our financial results:

- *For every $0.10 change in natural gas prices our annual cash flow increases by $1 million.*

- *If the current price of $4.75/mcf is sustained, we stand to gain $10 million in cash flow and our debt will drop to 1.6 times cash flow.*
- *With incremental cash flow of $10 million, we could add another 20 wells to our drilling programs.*

Production Momentum

Central Alberta remains our focus of low risk growth. In 2001, we invested a considerable amount in gas processing infrastructure and all of our core areas now have available capacity of about 50 mmcf/d. This means that in 2002, our capital spending can be dedicated to drilling. We expect to see significant low-cost reserve additions that can generate cash flow quickly.

Our production growth has gained momentum with our newest core area, Rycroft, coming on production in December. We acquired the Peace River Arch property in January 2001, and we are actively exploring for new gas reserves with prolific production rates, with some wells producing as much as five mmcf/d. With our current production of 33 mmcf/d and 1,400 bbls/d, Thunder's Q1 boe volumes are on track to increase about 20% over Q1 2001. Natural gas volumes are already up 40% over Q1 2000.

Plans for 2002

Thunder's 2002 capital program will be in line with cash flow. We remain cautious, but planning is underway to ramp up the drilling program based on evolving expectations for 2002 cash flow.

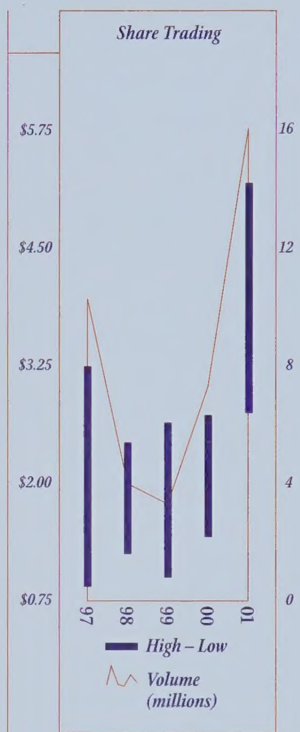
- *+125 drill-ready gas locations are in inventory, and plant capacity is available in all of our core areas.*
- *Our response time is fast. We bring new wells onstream in less than 50 days from spud date to flowing production, which means we benefit quickly from any rise in the market.*

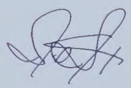
Our current budget is down 40% from last year at $30 million, but that spending is based on a gas price forecast of $3.50/mcf. That translates to only a 15% reduction in our drilling to 40 wells. Current plans call for 85% of drilling to be in central Alberta where we can add low risk, predictable growth, with 15% being directed toward our high risk, more prolific Rycroft property.

However, we are prepared to increase capital spending and ramp up drilling if current gas prices are sustained over the next few months. We have the drilling inventory, available capacity and the operational savvy to quickly benefit from a higher price environment.

In Closing

Last year's volatile markets demanded hard work from our employees and I would like to thank them for their always-reliable efforts. I would also like to acknowledge our Board of Directors for their insight and guidance during a volatile year. To our shareholders, thank you for your support. We remain a profit-driven company, well positioned to capture significant growth in our operations, and financial strength as we enter the up-cycle in natural gas markets.





Douglas A. Dafoe
President &
Chief Executive Officer
March 22, 2002

Operations

- Our 90% drilling success for the past six years has consistently added low-cost reserves.
- Major investments in infrastructure led to higher finding and development costs in 2001.
- Drilling in 2002 is expected to reduce finding and development costs to Thunder's more normal $6.00 – $8.00/boe for proved reserves.

Exploration and Development

Historical Drilling Results

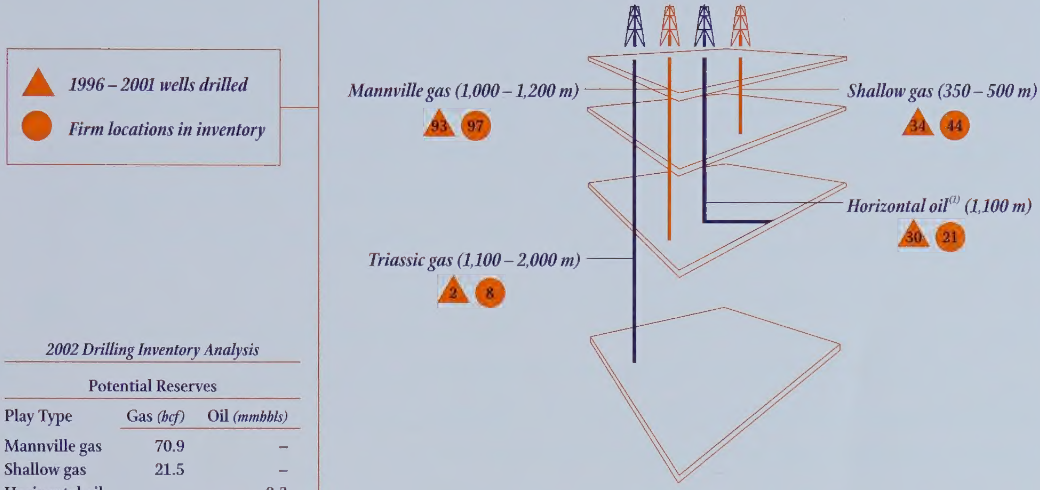
As part of our drilling analysis, we regularly update an internal study of all wells drilled since the company's inception six years ago. To the end of 2001, we had drilled a total of 159 wells. Historically, all wells, including unsuccessful wells, have yielded a finding and development cost ranging from $4.76/boe to $5.30/boe, based on cumulative production and remaining proved reserves in the 2001 year-end reserve report prepared by independent engineers, Sproule Associates Limited. From inception, our drilling program has yielded a proved recycle ratio of 2.2:1 (2.6:1 for the most recent three-year average). For all prospect types, we have added proved reserves of 119,000 boe per well with average initial productivity of 137 boe/d. The results are summarized below:

1996 – 2001 Historical Drilling Results

	Average Proved Reserves		Initial Production	Capital Costs in Today's Environment(1)	
Play Type	Gas *(mmcfe)*	Oil *(mboe)*	*(boe/d)*	Per Well *($000s)*	Per boe
Mannville gas	731	–	77	580	4.76
Shallow gas	489	–	48	390	4.79
Horizontal oil	–	160	175	840	5.30
Triassic gas (2)	1,500	–	250	750	3.00

(1) Includes estimated costs for drilling, completion, tie-in and an allocation for land, seismic and wellsite facilities. These estimates do not include plant or battery facility and pipeline costs which to date have cost the company an additional $1.29/boe.

(2) Using a 30% success factor on an exploration target of 5.0 bcf per well. Thunder had only drilled two wells to December 31, 2001 and we are still gathering data in this new exploration area.



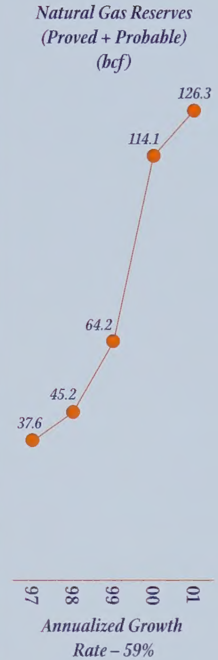
2002 Drilling Inventory Analysis

	Potential Reserves	
Play Type	Gas *(bcf)*	Oil *(mmbbls)*
Mannville gas	70.9	–
Shallow gas	21.5	–
Horizontal oil	–	2.3
Triassic gas	6.0	–
Total(1)	98.4	2.3

(1) Horizontal oil was calculated using a reduced 110 mbbls per well, which is the expectation from our second oil pool at Rosalind.

Reserve Potential – Current Drilling Inventory

Using data from our historical results, we have analyzed the potential of our current asset base. Based on 170 firm drilling locations currently in inventory, we see the potential of adding 98.4 bcf of natural gas reserves and 2.3 mmbbls of crude oil reserves. The table on the left summarizes this analysis.



THUNDER HAS THE POTENTIAL TO **grow existing gas** RESERVES BY 80% AND OIL BY 30% BASED ON THE CURRENT INVENTORY OF FIRM DRILLING LOCATIONS.

Property Review

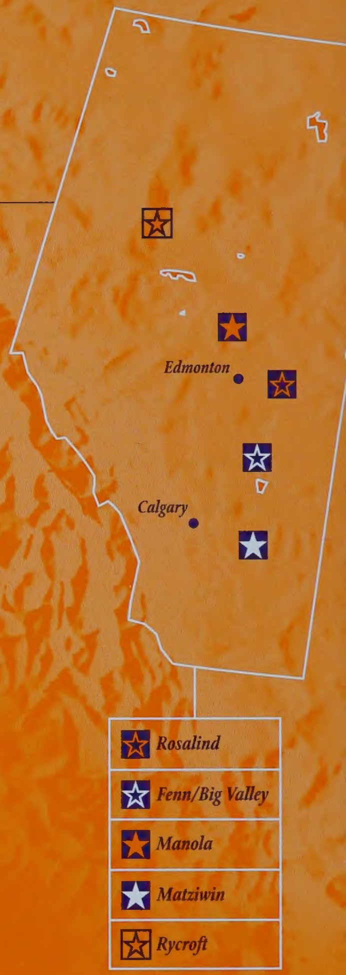
Thunder's Operational Template

Over the past six years, Thunder has created an operational template which is applied to new core areas immediately following acquisition. We operate all of our core areas at high working interests, and have established a large drilling inventory – both of which give us the flexibility to respond quickly to either a bear or bull commodity price market. As a heavily-weighted gas producer, we also work to have plant capacity available to bring production on quickly and control our volumes.

Central Alberta is our main operational focus in which we operate four core areas. All four contain predominantly multi-zone shallow gas plays, with low to medium risk drilling and a well developed infrastructure. Our 90% drilling success rate over the past six years reflects our indepth technical knowledge of these properties.

In January 2001, we gained entry into the Peace River Arch in northern Alberta, a natural gas area known for its prolific production rates, multi-zone potential and large reserve targets. Thunder operates the Rycroft property and holds a 50% working interest in the joint lands. This acquisition provided an excellent opportunity to move our operational template from central Alberta to an area with the potential for higher rewards.

- **Thunder operates all five of its core areas.**
- **Production was 76% natural gas in 2001.**
- **All areas have plant capacity available allowing new gas volumes to be brought onstream quickly.**



Central Alberta

Rosalind

Rosalind is Thunder's major gas and oil producing property, a growth scenario that has been driven by a quadrupling of gas production and the discovery of two oil pools since 1996. We have an average 90% working interest in 146 sections of land.

2001

- *Drilling resulted in five gas wells (5.0 net), five horizontal oil wells (4.9 net) and two dry holes (2.0 net). This brought year-end production to 12.1 mmcf/d of natural gas and 933 bbls/d of oil and NGLs.*
- *Two plant expansions were completed in 2001. A debottlenecking of sour gas processing and pipeline systems added 3.0 mmcf/d to plant capacity bringing total raw gas capacity to 15 mmcf/d. Existing facilities have room for another 1.5 mmcf/d. Available third-party processing will allow another 2.0 mmcf/d to be brought onstream.*
- *Our oil treating facilities were expanded with the installation of water handling facilities and a pipeline, which will allow for further development of our second horizontal oil pool.*

2002

- *Drilling of natural gas targets will continue with five wells (5.0 net) planned.*

Fenn/Big Valley

Thunder has been particularly successful in adding production volumes through drilling at Fenn/Big Valley, a core area acquired in 1999. Thunder holds a 93% interest in 77 sections of land.

2001

- *Thunder drilled nine successful gas wells (9.0 net) and two successful oil wells (1.8 net).*
- *Thunder has total gas plant capacity of 8.0 mmcf/d, with access to third-party processing adding another 2.0 mmcf/d of gas processing. Additional investment in compression would add another 4.0 mmcf/d of capacity to the area.*
- *Year-end production at Fenn/Big Valley was 5.7 mmcf/d of gas and 114 bbls/d of oil.*

2002

- *First quarter 2002 drilling has added three successful gas wells and production has increased to 7.5 mmcf/d. Plans for the year include a seven-well program (7.0 net) of shallow gas wells and three deeper Mannville tests (3.0 net).*

- **Drilling in 2002 will focus on low to medium risk gas prospects in central Alberta.**
- **The pace of drilling will be increased as gas prices rise.**

Manola

Multi-zone exploration and development drilling at Manola continued to increase production in 2001. Thunder holds a 97% working interest in 121 sections of land.

2001

- *We successfully drilled and completed 10 gas wells (9.5 net) and one well was dry and abandoned (1.0 net).*
- *The gas gathering system was expanded to handle new production from successful wells and future drilling. Plant capacity exists for another 3.5 mmcf/d of raw gas.*
- *Year-end production from Manola was 6.5 mmcf/d of natural gas and 202 bbls/d of crude oil and NGLs.*

2002

- *Natural gas drilling will be focused along our newly expanded gathering system with a total of five wells (5.0 net) planned.*

Matziwin

Thunder's operational template of low cost drilling and ensuring available processing infrastructure has continued to bring growth at Matziwin. Thunder's working interest is 90% in 65 sections of land.

2001

- *Drilling resulted in five gas wells (4.8 net) and one oil well (1.0 net).*
- *We optimized our oil and gas gathering system. Current capacity at Matziwin is 8.0 mmcf/d, of which about 1.5 mmcf/d is available for new production.*
- *Year-end production increased to 4.6 mmcf/d and 190 bbls/d of crude oil and NGLs.*

2002

- *A total of five wells (5.0 net) are planned for the area.*

Peace River Arch

Rycroft

The purchase of Rycroft has given Thunder a foothold in the Peace River Arch where reserve targets are larger and production rates more prolific than in our other core areas. Thunder acquired this property in January 2001, and is the operator with a 50% working interest in the joint lands. The acquisition provided an excellent opportunity to move our operational template from central Alberta to an area with the potential for higher rewards. At the time of acquisition, Rycroft was a non-producing property with three shut-in wells. The first well commenced production in September and, following construction of a plant, the other shut-in wells were brought onstream, on schedule, in early December.

Rycroft Characteristics

- *Thunder operates and holds a 46% interest in 78 sections of land, 66 of which are undeveloped, including six sections purchased at a January 2002 Crown land sale.*
- *The area is multi-zone with gas producing from the Bluesky/Gething zones at 1,150 metres, the Doig formation at 1,450 metres and the Debolt formation at 2,000 metres.*
- *Thunder's share of natural gas reserves is estimated at 5.9 bcf of proved and 0.5 bcf of probable at December 31, 2001.*

2001

- *Year-end exit rate was 8.2 mmcf/d (4.1 mmcf/d net) of natural gas and 13 bbls/d (6.5 bbls/d net) of NGLs.*
- *The gas plant completed in December has capacity of 25 mmcf/d (5.7 mmcf/d net), and is a zero-emissions facility capable of processing both sweet and sour natural gas reserves.*
- *A 50-square mile 3-D seismic survey was shot in the fall of 2001 and a number of prospects were identified.*

2002

- *From prospects identified on 3-D seismic, six sections of Crown land (3.0 net) were acquired in first quarter 2002.*
- *Five exploration natural gas wells (2.3 net) were drilled in the first quarter resulting in one gas well (0.5 net), three suspended wells (1.3 net) and one well (0.5 net) was dry and abandoned.*
- *Further plans for the year include six exploration wells (3.0 net) to be drilled over the balance of the year.*

Undeveloped Land Holdings (net acres)

Annualized Growth Rate – 193%

Increase in Land Holdings

In 2001, Thunder's undeveloped land inventory rose 22% to 169,787 net acres, an increase of approximately 30,000 acres over last year. The majority of new lands came through the Rycroft acquisition, but we also spent $3.5 million on Crown and freehold land in 2001 as we continue to expand our land base in our core central Alberta properties.

Land Holdings	Developed Acres		Undeveloped Acres		Total Acres	
As at December 31, 2001	Gross	Net	Gross	Net	Gross	Net
Rosalind	50,440	43,191	43,276	41,597	93,716	84,788
Manola	14,880	13,910	62,400	61,279	77,280	75,188
Fenn/Big Valley	25,939	23,171	23,512	22,666	49,451	45,837
Matziwin	15,520	13,933	26,021	23,567	41,541	37,499
Rycroft	7,200	2,640	38,670	18,503	45,870	21,143
Other	640	480	5,760	2,175	6,398	2,656
Total	114,619	97,325	199,639	169,787	314,256	267,111

High Drilling Success Continued

Thunder's high drilling success rate continued in 2001 at 89% based on participation in 44 wells, all of which were operated by the company. Nineteen of the wells were exploratory and 25 were development wells. Natural gas was the main focus at 31 wells, with the main emphasis being our central Alberta core areas. Twelve wells were drilled at Rosalind, 11 at Manola, 12 at Fenn/Big Valley, six at Matziwin and three at Rycroft in the Peace River Arch. The company also farmed out 11 wells. Thunder's drilling inventory currently stands at 170 firm locations. Total company 2001 reserve additions from the drill bit amounted to 22 bcf and 566 mbbls.

Drilling Activity	2001		2000	
Years ended December 31	Gross	Net	Gross	Net
Gas	31	29.2	20	18.3
Oil	8	7.7	12	12.0
Dry	5	4.5	3	3.0
Total	44	41.4	35	33.3
Success rate *(%)*	89		91	
Average working interest *(%)*	94		95	

Reserve Growth

Company reserves grew by 9% during the year to 28.7 million boe. Additions from acquisitions totaled 1.0 million boe, while drilling accounted for 4.2 million boe. Thunder continued to emphasize natural gas drilling, with net natural gas additions making up 87% of the total reserves added through the drill bit during the year. Proved undeveloped oil reserves represent infill locations for Thunder's horizontal oil pools at Rosalind. Proved undeveloped gas consists largely of wells that are awaiting tie-in and oil pool gas cap reserves. Proved non-producing gas reserves are principally second zones behind pipe of existing producers. Proved producing reserves increased to 72% of total proved reserves as compared to 60% in 2000.

Reserves *(as at January 1, 2002 determined by Sproule Associates Limited, independent consultants)*

	Remaining Reserves		Future Cash Flow Before Income Tax		
			Undiscounted	Discounted	
	Natural Gas *(bcf)*	Crude Oil & NGLs *(mbbls)*	*($000s)*	at 10% *($000s)*	at 12% *($000s)*
Proved developed					
Producing	72.0	4,301	268,114	161,299	149,905
Non-producing	18.5	248	75,779	17,460	14,514
Proved undeveloped	9.9	1,236	37,044	19,483	17,542
Total proved	100.4	5,785	380,937	198,242	181,961
Probable	25.9	1,865	97,230	39,239	34,437
Total	126.3	7,650	478,167	237,481	216,398

Reconciliation of Reserves	Gas *(bcf)*			Crude Oil *(mbbls)*			Boe *(mboe)*
	Proved	Probable	Total	Proved	Probable	Total	Total
January 1, 2001	93.1	21.0	114.1	5,663	1,685	7,348	26,365
Drilling	20.0	2.0	22.0	566	–	566	4,227
Acquisitions	5.0	0.3	5.3	79	–	79	954
Production	(9.5)	–	(9.5)	(548)	–	(548)	(2,126)
Revisions to prior estimates	(8.2)	2.6	(5.6)	25	180	205	(727)
January 1, 2002	100.4	25.9	126.3	5,785	1,865	7,650	28,693

Summary of Sproule Associates Limited Price Forecasts Reflected in Reserve Report

Year	WTI Cushing, Oklahoma[1] *(US$/bbl)*	Edmonton Par Price 40° API *(Cdn$/bbl)*	Thunder Corporate Natural Gas[2] *($/mcf)*
2002	19.90	29.86	3.71
2003	20.64	30.96	4.30
2004	21.12	31.67	4.36
2005	21.44	32.15	4.41
2006	21.76	32.65	4.54
2007	22.08	33.14	4.60
2008	22.42	33.65	4.69
2009	22.75	34.16	4.77
2010	23.09	34.68	4.84
2011	23.44	35.20	4.92
2012	23.79	35.74	5.02
2013	24.15	36.28	5.10
Thereafter	Escalation rate of 1.5% per year		

(1) 40° API

(2) This price was developed by blending gas sales contracts of the company, and adjusting for the average btu content of the gas.

Shareholder Value

Future cash flow estimates and related net asset value calculations for January 1, 2002 were down compared with January 1, 2001 due to lower commodity price forecasts used by Sproule. Last year's reserve report forecasted natural gas prices of $8.22/mcf and $6.02/mcf in years 2001 and 2002, respectively, compared with a realized price of $5.20/mcf in 2001 and the current forecast of $3.70/mcf in 2002. The reduction in natural gas cash flow due to the lower price forecast in those two years is estimated at $45 million, or $1.45 per share.

Net Asset Value
As at December 31 ($ thousands , except where noted)

	2001	2000	1999
Reserves discounted at 10% pre-tax[1]	217,862	233,255 [2]	77,655
Undeveloped land	16,979	13,970	5,608
Working capital deficiency	(3,144)	(1,887)	(5,108)
Bank debt	(68,538)	(52,853)	(11,825)
Net asset value – basic	163,159	192,485	66,330
Proceeds stock options	6,650	4,573	2,480
Net asset value – diluted	169,809	197,058	68,810
Per share amounts			
Basic *($)*	5.29	6.72	2.58
Diluted *($)*	5.06	6.37	2.50

(1) Probable reserves have been risked at 50%.

(2) Includes reduction of $10 million due to outstanding hedges.

Finding and Development Costs

Total capital spent in 2001 was $52.6 million resulting in proven and probable finding and development costs (F&D) of $10.14/boe before revisions, and $11.79/boe after revisions. During the year, we made a one-time investment of approximately $9.5 million in new facilities and infrastructure principally at Rycroft and Rosalind, and $1.5 million in a 3-D seismic program at Rycroft. These costs, which added $3.11/boe to the 2001 F&D costs, are expected to benefit the company in future drilling. The F&D cost for the most recent three-year period averaged $6.50/boe.

We experienced higher F&D costs for 2001 as we invested in major gas plant infrastructure, which does not contribute to current reserve additions. Gas processing capacity is now available in all of our core areas and, with 170 firm drilling locations in inventory, we expect F&D costs to return to our historical levels in 2002, which have been one of the lowest in the industry.

Finding and Development Costs *Years ended December 31 ($ thousands, except where noted)*	2001	2000	1999	Most recent 3 years
Finding and development costs				
Land and seismic	6,914	3,173	4,365	14,452
Drilling, completions and equipping	29,776	18,948	8,220	56,944
Acquisitions, net of dispositions	5,779	46,849	8,408	61,036
Facilities and pipelines	10,093	1,534	787	12,414
Total finding costs	52,562	70,504	21,780	144,846
Reserve additions				
Proved				
Gas *(mmcf)*	16,861	47,539	16,635	81,035
Oil *(mbbls)*	671	3,035	828	4,534
Boe *(mboe)*	3,481	10,958	3,601	18,040
Probable				
Gas *(mmcf)*	4,759	9,364	5,886	20,009
Oil *(mbbls)*	181	976	(244)	913
Boe *(mboe)*	974	2,537	737	4,248
Costs per boe *($)*				
Proved	15.09	6.43	6.05	8.03
Proved plus probable	11.79	5.22	5.02	6.50

Netbacks and Recycle Ratios *Years ended December 31*	2001	2000	1999	3-Year Average
Operating netbacks[(1)] *($/boe)*	19.56	23.22	11.19	21.03
Recycle ratios				
Proved reserves	1.3	3.6	1.8	2.6
Proved and probable reserves	1.7	4.4	2.2	3.2

(1) Includes revenue less royalties and operating costs and before hedging cost.

- **2001 F&D costs included costs associated with major infrastructure. F&D costs in 2002 are expected to return to more historic levels.**

The following discussion is management's analysis of Thunder Energy's operating and financial data for 2001 and prior years, as well as estimates of future operating and financial performance based on information currently available.

Management's Discussion and Analysis

Forward Looking Statements

Statements throughout this annual report that are not historical facts may be considered "forward looking statements." These forward looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the company's objectives, goals or future plans are forward looking statements. Since forward looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to any number of factors, including such variables as new information regarding recoverable reserves, changes in demand for, and commodity prices of crude oil and natural gas, legislative, environmental and other regulatory or political changes, competition in areas where the company operates and other factors discussed in this annual report.

Financial Results ($ thousands, except per share amounts)	2001	2000	1999
Petroleum and natural gas sales	63,874	56,444	15,431
Cash flow from operations	26,205	26,805	7,785
Per share – basic	0.87	0.99	0.35
Per share – diluted	0.84	0.95	0.34
Net income	8,072	10,671	2,437
Per share – basic	0.27	0.39	0.11
Per share – diluted	0.26	0.38	0.11
Capital expenditures	52,607	70,552	21,891
Net debt	71,682	54,737	16,934
Net asset value (1)	169,809	197,058	68,810
Per share – basic	5.29	6.72	2.58
Per share – diluted	5.06	6.37	2.50

(1) Using a 10% discount rate for estimated future net revenues of oil and gas reserves (based on escalated commodity prices and costs) before income taxes.

Petroleum and Natural Gas Sales

Petroleum and natural gas sales increased 13% to $63.9 million in 2001 compared with $56.4 million in 2000 and $15.4 million in 1999. The $7.5 million increase in 2001 was from higher natural gas and crude oil volumes, offset by price decreases for both crude oil and natural gas. Natural gas continued to be a more significant contributor increasing to 78% of total revenues as compared to 68% in 2000.

Petroleum and Natural Gas Sales *($ thousands)*	2001	2000	1999
Natural gas	49,612	38,138	9,061
Crude oil and NGLs	14,262	18,306	6,370
Total	63,874	56,444	15,431

Sales Variance Analysis *($ thousands)*	2001	2000	1999
Natural gas sales			
Volume increase	13,539	9,640	1,166
Price increase (decrease)	(2,065)	19,437	2,252
Net gas sales change	11,474	29,077	3,418
Crude oil and NGLs sales			
Volume increase (decrease)	1,083	5,489	(489)
Price increase (decrease)	(5,127)	6,447	2,489
Net crude oil and NGLs sales change	(4,044)	11,936	2,000
Combined sales change	7,430	41,013	5,418

Production	2001	2000	1999
Natural gas *(mcf/d)*	26,113	19,206	9,347
Crude oil and NGLs *(bbls/d)*	1,501	1,413	761
Total *(boe/d)*	5,853	4,614	2,319
Percentage gas	74	69	67

Average Selling Price	2001	2000	1999
Natural gas *($/mcf)*	5.20	5.42	2.66
Crude oil and NGLs *($/bbl)*	26.03	35.28	22.94
Total *($/boe)*	29.90	33.37	18.23

- **Despite declines in commodity prices, revenues were up 13% due to production increases.**
- **Natural gas sales made up 78% of revenues.**

Marketing

The company markets its natural gas in the Alberta spot market and through aggregators, which sell to major markets in Canada and the United States. Aggregator prices are based on a combination of term and spot markets. Crude oil and NGLs are sold on a spot basis at various delivery points in Alberta. Prices received for crude oil and NGLs are determined by the quality of the crude compared to a benchmark price for light sweet oil. Thunder's composite crude oil is a medium blend averaging approximately 25° API.

- To capture pricing upside, a higher proportion of gas is being sold into the Alberta spot markets.

Thunder continues to direct new gas sales to the higher value Alberta spot market. In 2001, 53% of natural gas sales went to the Alberta spot markets as compared to 50% in 2000. With the addition of new gas production in the fourth quarter, Thunder is currently selling 62% of its natural gas to the Alberta spot market.

Thunder's average price for crude and NGLs was discounted to the Edmonton light posted price by $13.15/bbl (2000 – $9.02/bbl). The quality of Thunder's crude remained at 25° API, although it sold at a higher discount in 2001 due to market conditions. Currently, the discount for Thunder's crude has reverted to more historical levels and is estimated at $7.00/bbl.

Price Realization	2001	2000	1999
Natural gas *($/mcf)*			
Benchmark – average Alberta spot price	5.27	5.01	2.77
Thunder realized price	5.20	5.42	2.66
Premium (discount)	(0.07)	0.41	(0.11)
Crude oil and NGLs *($/bbl)*			
Benchmark – Edmonton 40° API	39.18	44.30	27.29
Thunder realized price	26.03	35.28	22.94
Discount	(13.15)	(9.02)	(4.35)

Royalties

Thunder's overall royalty rate increased to 20% of revenues, up from 18% in 2000. The rate increase was largely due to the greater proportion of production generated from Crown lands in 2001, which have a higher royalty rate than freehold lands.

Royalties *($ thousands)*	2001	2000	1999
Crown	10,157	7,883	1,423
Freehold and other	2,908	2,905	1,237
Total gross royalties	13,065	10,788	2,660
ARTC	(290)	(532)	(367)
Net royalties	12,775	10,256	2,293

Royalty Rates (as % of revenue)	2001	2000	1999
Crown	16	14	9
Freehold and other	5	5	8
Total gross royalties	21	19	17
ARTC	(1)	(1)	(2)
Net royalties	20	18	15

Hedging

In conjunction with the Core Area Acquisition in 2000, and the resulting increased leverage taken on by the company, Thunder sold forward 1,000 bbls/d of oil production for the six months ended June 30, 2001 (2000 – 934 bbls/day for the nine months ended December 31). For natural gas, Thunder sold forward 17,000 GJs/day for the three months ended March 31, 2001 (2000 – 15,345 GJs/day for the nine months ended December 31). These hedges resulted in a hedging cost of $10.5 million in 2001 and $7.8 million in 2000. Despite these costs, the hedges provided assured cash flow for Thunder to maintain an active drilling program and, at the same time, make fixed debt repayments in 2000. The company currently has no production hedges in place and, at the present time, is not contemplating hedging future production.

2001 Hedging				Hedging Cost	
	Volume	Thunder Received	Thunder Paid	Per Unit	Amount *($000s)*
Crude oil	*(bbls/d)*	*(Cdn$ NYMEX per bbl)*			
January to June	1,000	33.88	43.65	9.77	1,725
Natural gas	*(GJs/d)*	*(Cdn$ AECO per GJ)*			
January to March	17,000	4.61	10.33	5.72	8,756
Total 2001 hedging cost					10,481

2000 Hedging				Hedging Cost	
	Volume	Thunder Received	Thunder Paid	Per Unit	Amount *($000s)*
Crude oil	*(bbls/d)*	*(Cdn$ NYMEX per bbl)*			
April to December	934	37.50	46.38	8.88	2,229
Natural gas	*(GJs/d)*	*(Cdn$ AECO per GJ)*			
April to December	15,345	4.17	5.50	1.33	5,611
Total 2000 hedging cost					7,840

Operating Expenses

Operating expenses increased to $9.3 million in 2001 from $6.9 million in 2000 due to higher production volumes and increases in electricity costs, along with general increases in the cost of goods and services related to the intense activity in the industry, especially in the first nine months of 2001. On a unit basis, operating costs increased 7% to $4.36/boe from $4.09/boe in 2000.

Operating Costs	2001	2000	1999
Operating costs *($ thousands)*	9,310	6,912	3,663
Per boe *($/boe)*	4.36	4.09	4.33

General and Administrative Expenses

Thunder's general and administrative (G&A) expenses on a unit basis increased marginally to $0.78/boe from $0.77/boe in 2000. On an absolute basis, net G&A expenses increased by $379,000, the bulk of which came from higher employee costs. Thunder does not capitalize any indirect G&A expenses. At year-end 2001, the company had 16 full-time employees and four consultants at its head office. Field staff consisted of five full-time employees and six contract operators.

General and Administrative Expenses ($ thousands, except where noted)	2001	2000	1999
Gross G&A expenses	3,314	2,431	1,846
Overhead recoveries	(1,646)	(1,142)	(1,012)
Net G&A expenses	1,668	1,289	834
Net G&A expenses per boe *($)*	0.78	0.77	0.99

Interest Expense

Interest expense remained flat at $3.1 million in 2001 compared with 2000. Although our average debt for the year increased to $56.7 million in 2001 from $39.4 million in 2000, the average interest rate decreased to 5.5% in 2001 from 7.9 % in 2000. The company is currently borrowing money at 3.6%. Thunder's current line of credit is $80 million. This credit line is used on a revolving basis and interest is charged at prime. Long-term debt at December 31, 2001 stood at $68.5 million. This level represents 2.6 times 2001 cash flow and 2.3 times estimated 2002 cash flow.

Depletion, Depreciation and Amortization

Depletion, depreciation and amortization (DD&A) charges increased to $13.0 million in 2001 from $8.6 million in 2000. This increase was due to higher production levels and higher depletion costs on a per unit basis. The DD&A rate increased to $6.08/boe from $5.12/boe in the prior year. The higher 2001 rate relates largely to increases in land and facilities costs relative to the total capital expenditures, activities that do not directly or immediately add reserves. At December 31, 2001, Thunder had a ceiling test cushion of approximately $29 million based on December 2001 Edmonton posted price of $29.24/bbl for crude oil and wellhead prices of $21.46/bbl for NGLs and $3.27/mcf for natural gas.

Depletion, Depreciation and Amortization *($ thousands, except where noted)*	2001	2000	1999
Oil and gas depletion	9,291	6,184	2,415
Oil and gas depreciation	3,270	2,229	1,125
Other depreciation	40	29	15
Future site restoration	386	204	135
Total	12,987	8,646	3,690
DD&A rate *($/boe)*	6.08	5.12	4.36

Income Taxes

Total income tax provision decreased to $5.5 million from $7.7 million in 2001 reflecting lower earnings during the year and a lower effective tax rate. The 2001 provision was comprised of $5.2 million in future taxes (2000 – $7.5 million) and $0.3 million related to the large corporation tax (2000 – $0.2 million). The effective tax rate was 40.3%, down from 41.9% in 2000, largely due to a decrease in the Alberta provincial income tax rate in 2001. There was no cash income tax provision in 2001 and none is expected in 2002. In the current commodity price environment, no cash income taxes are expected until 2004.

Tax Pools *($ thousands at December 31)*	2001	2000
Canadian oil and gas property expense (COGPE)	44,617	41,080
Canadian development expense (CDE)	12,005	8,773
Canadian exploration expense (CEE)	7,831	–
Undepreciated capital cost (UCC)	36,963	25,495
Non-capital losses	–	1,552
Share issue costs	1,573	1,475
Total	102,989	78,375

Cash Flow from Operations

Cash flow from operations decreased marginally to $26.2 million in 2001 from $26.8 million in 2000, and basic cash flow per share decreased 12% to $0.87 from $0.99 in 2000. The production growth was more than offset by lower commodity prices, which reduced netbacks per boe produced.

Cash Flow	2001	2000	1999
Cash flow from operations *($ thousands)*	26,205	26,805	7,785
Per share – basic *($)*	0.87	0.99	0.35
Per share – diluted *($)*	0.84	0.95	0.34
Cash flow per boe *($)*	12.27	15.83	9.20
Cash flow as a percentage of gross sales	41%	47%	50%

Net Income

Net income decreased 24% to $8.1 million in 2001 from $10.7 million in 2000 reflecting the lower cash flow resulting from lower commodity prices. Shareholders' return on average equity was 16% for the year.

Net Income	2001	2000	1999
Net income *($ thousands)*	8,072	10,671	2,437
Per share – basic *($)*	0.27	0.39	0.11
Per share – diluted *($)*	0.26	0.38	0.11
Net income per boe produced *($)*	3.82	6.17	2.88
Return on shareholders' equity *(%)*	16	30	11
Return on capital employed *(%)*	6	14	7

Netback Analysis	Natural Gas *($/mcf)*			Crude Oil *($/bbl)*		
	2001	2000	1999	2001	2000	1999
Selling price	5.20	5.42	2.66	26.03	35.28	22.94
Royalties (net of ARTC)	1.03	1.13	0.43	3.05	4.53	2.26
Hedging cost	0.92	0.80	–	3.14	4.29	–
Production expenses	0.67	0.60	0.59	4.87	5.15	5.94
Operating netback	2.58	2.89	1.64	14.97	21.31	14.74

	($/boe)		
	2001	2000	1999
Selling price	29.90	33.37	18.23
Royalties (net of ARTC)	5.98	6.06	2.71
Hedging cost	4.91	4.64	–
Production expenses	4.36	4.09	4.33
Operating netback	14.65	18.58	11.19
General and administrative	0.78	0.77	0.99
Interest	1.46	1.85	0.93
Large corporation tax expense	0.15	0.13	0.07
Cash flow netback from operations	12.26	15.83	9.20
Depletion, depreciation and site restoration	6.08	5.12	4.36
Taxes (future)	2.41	4.54	1.96
Net earnings	3.77	6.17	2.88

Capital Expenditures

Thunder's total capital expenditures amounted to $52.6 million in 2001. During the year $29.8 million was directed to drilling activities, $6.9 million to land and seismic and $10.1 million was spent on facilities and pipelines. The company spent $5.8 million on acquisitions including the purchase of Rycroft.

Capital Expenditures Summary *($ thousands)*	2001	2000	1999
Land and rentals	3,457	2,363	3,700
Seismic	3,457	810	665
Drilling, completions and equipping	29,776	18,948	8,220
Facilities and pipelines	10,093	1,534	787
Property acquisitions, net of dispositions	5,779	46,849	8,408
Administrative assets	45	48	111
Total	52,607	70,552	21,891

Capital Efficiency

Thunder's 2001 proved finding and development costs (F&D) were $10.92/boe before revisions, and $15.09/boe after revisions. The three-year average for proved F&D costs was $6.83/boe before revisions, and $8.03/boe after revisions. During the year, Thunder made a one-time investment in approximately $9.5 million in new facilities and infrastructure principally at Rycroft and Rosalind and $1.5 million in a 3-D seismic program at Rycroft. These costs, which added $2.73/boe to the 2001 proved F&D costs, are expected to benefit the company in future drilling. The company's recycle ratio in 2001 was 1.3 for proved reserves and 1.7 for proved plus probable reserves. The company's reserve replacement ratio was 1.8 in 2001.

Proved Finding and Development Costs by Category ($)	2001	2000	1999	Three Year Average
Drilling				
Land and rentals	0.89	0.60	2.16	0.99
Seismic	0.89	0.20	0.39	0.52
Drilling, completions and equipping	7.63	4.79	4.80	5.95
Facilities and pipelines	2.58	0.39	0.46	1.29
Total drilling	11.99	5.98	7.81	8.75
Acquisitions	6.37	5.08	4.89	5.17
Average drilling and acquisitions	10.92	5.31	7.01	6.83
Reserve revisions	4.17	1.12	(0.96)	1.20
Total	15.09	6.43	6.05	8.03

Capital Program Efficiency ($/boe)	2001	2000	1999	Three Year Average
Operating netback before hedging cost	19.56	23.22	11.19	21.03
Proved reserves				
Finding and development costs	15.09	6.44	6.05	8.03
Recycle ratio	1.3	3.6	1.8	2.6
Proved plus probable reserves				
Finding and development costs	11.79	5.22	5.02	6.50
Recycle ratio	1.7	4.4	2.2	3.2
Reserves replacement ratio *(%)*	180	795	457	–

Liquidity and Capital Resources

The company's $52.6 million capital expenditure program in 2001 was financed with $26.2 million in cash flow, $15.7 million in bank debt, $9.5 million in new equity and $1.2 million in working capital. The new equity consisted of a public offering of 2,000,000 common shares at a price of $5.00 per share for net proceeds of $9.2 million and an additional 208,299 shares issued through the exercise of stock options at an average exercise price of $1.09 per share. At December 31, 2001, Thunder's debt and working capital deficit represented 40% of total capitalization.

Thunder's current line of credit is $80 million. The company expects to fund the 2002 capital program with internally-generated cash flow and, although quarterly fluctuations in funding levels are expected, the objective is to remain at the current net debt level throughout the year. Thunder's goal is to reduce its debt to cash flow ratio to less than 2.0 times estimated future cash flows by the end of 2002.

Total Capitalization *($ thousands)*	2001	2000	1999
Working capital deficiency	3,144	1,885	5,109
Long-term debt	68,538	52,852	11,825
Future income taxes	19,841	15,019	1,930
Future site restoration	811	425	311
Market value of common shares at December 31	84,875	78,229	51,487
Total	177,209	148,410	70,662

Thunder Market Guidance for 2002

Thunder expects to fund the 2002 capital expenditure program of $25 to $30 million with internally-generated cash flow. Cash flow will be dependent on a number of variables including forecasted prices and production. The table below outlines a range for these critical assumptions. Thunder expects to drill between 35 and 45 net wells in 2002, from the current inventory of 170 firm locations available to the company.

($ thousands, except where noted)	2002 Target Range	2001 Actual
Financial		
Cash flow from operations	25,000 – 30,000	26,205
Per share – basic	0.81 – 0.97	0.87
Net income	7,000 – 8,500	8,072
Per share – basic	0.23 – 0.28	0.27
Capital expenditures	25,000 – 30,000	52,607
Foreign exchange rate *(US$ to Cdn$)*	0.633	0.646
Interest rate	5%	5.5%
Operations		
Average daily production		
Natural gas *(mmcf/d)*	33.0 – 35.0	26.1
Crude oil and NGLs *(bbls/d)*	1,200 – 1,400	1,501
Natural gas price		
Henry Hub *(US$/mmbtu)*	2.70	4.05
Alberta spot *($/mcf)*	3.50	5.27
Thunder wellhead *($/mcf)*	3.50	5.20
Crude oil price		
WTI *(US$/bbl)*	22.00	25.95
Edmonton posted *($/bbl)*	32.79	39.18
Thunder wellhead *($/bbl)*	26.50	26.03

Cash Flow Sensitivities	Cash Flow *($ thousands)*	Per Share Basic
Natural gas price change of $0.10/mcf @ Thunder wellhead	1,000	$0.03
Natural gas production change of 1 mmcf/d	1,000	$0.03
Crude oil and NGLs price change of $1.00 per bbl @ Thunder wellhead	400	$0.02
Crude oil and NGLs production change of 100 bbls/d	700	$0.02
Interest rate change of 1%	700	$0.02
Foreign currency change of $0.01 *($US to $Cdn)*	350	$0.01

Business Risks and Risk Management

The oil and gas industry is exposed to numerous business risks which can materially affect performance and financial results. Thunder has taken many steps to mitigate these risks.

With respect to commodity prices, Thunder, in limited circumstances, uses commodity price derivative instruments to hedge the company's exposure to fluctuations in oil and gas pricing. In addition, Thunder strives to be a low cost producer with low finding and development costs, G&A costs and operating expenses. Thunder also focuses on investments that will generate immediate cash flow from new production. On average over the past three years,Thunder has maintained recycle ratios, which is a measure of costs to operating netbacks, in excess of 2.6 times proved reserve addition costs.

In reference to exploration and production risks, Thunder operates substantially all of its exploration and development programs. This provides control over drilling locations, timing and capital commitments. Thunder maintains a prudent position on the risk/reward spectrum by working in areas with multiple oil and gas targets and where dry hole exposures are generally less than $500,000 per well. The company's exploration and development programs are focused in core areas where it has the experience and history of profitably adding oil and natural gas reserves, and operated facilities provide competitive advantages and ensure new production is brought onstream in a timely manner. Reservoir performance can affect future cash flow projections and reserve evaluations. Thunder is in daily contact with its field staff to track production performance and, to the extent possible, takes immediate corrective action if any adverse situation should arise.

While current market conditions may restrict capital availability to the oil and gas industry, Thunder will maximize its access to capital markets by striving to maintain a strong financial and operational track record. Thunder's objective is to maintain a debt to future cash flow ratio at or below 2.0 times projected annual cash flow. The company will manage market expectations to the greatest degree possible by establishing and meeting reasonable production targets. Over the long term, Thunder expects capital markets to strengthen as a result of continued strength in natural gas prices, attractive returns for oil and gas investments, low interest rates and inflation, and strong economic growth rates.

Management's Report

The accompanying financial statements of Thunder Energy Inc. have been prepared by management in accordance with generally accepted and consistently applied accounting principles. The company's accounting procedures and related systems of internal controls are designed to provide reasonable assurance that its assets are safeguarded and its financial records are reliable. In recognizing that the company is responsible for both the integrity and objectivity of the financial statements, management is satisfied that these financial statements have been prepared accordingly and within reasonable limits of materiality. Further, management is satisfied that the financial information throughout the balance of this annual report is consistent with the information presented in the financial statements.

Ernst & Young LLP have been appointed by the shareholders of Thunder and serve as the company's independent auditors. They have examined the financial statements of the company for the year ended December 31, 2001. The Audit Committee has reviewed these statements with management and the auditors, and has reported to the Board of Directors. The Board has approved the financial statements of Thunder which are contained in this annual report.

Douglas A. Dafoe
President and
Chief Executive Officer
March 12, 2002

Brent T. Kirkby
Vice President, Finance
and Chief Financial Officer

Auditors' Report

To the Shareholders of Thunder Energy Inc.

We have audited the consolidated balance sheets of Thunder Energy Inc. as at December 31, 2001 and 2000 and the consolidated statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Calgary, Canada
March 12, 2002

Ernst + Young LLP
Chartered Accountants

Consolidated Balance Sheets

As at December 31 *(thousands of dollars)*	2001	2000
ASSETS [note 4]		
Current		
Accounts receivable	$ 5,902	$ 9,489
Prepaid expenses	793	367
	6,695	9,856
Property and equipment [note 3]	153,309	113,303
	$ 160,004	$ 123,159
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Bank indebtedness	$ 168	$ 3,828
Accounts payable and accrued liabilities	9,671	7,913
	9,839	11,741
Long-term debt [note 4]	68,538	52,852
Future site restoration costs	811	425
Future income taxes [note 6]	19,841	15,019
	99,029	80,037
Commitments [note 7]		
Shareholders' equity		
Share capital [note 5]	39,710	29,929
Retained earnings	21,265	13,193
	60,975	43,122
	$ 160,004	$ 123,159

See accompanying notes.

On behalf of the Board:

J W Peltier

Director

Jim Pasieka

Director

Consolidated Statements of Income and Retained Earnings

Years ended December 31 *(thousands of dollars, except per share amounts)*

	2001	2000
Revenue		
Petroleum and natural gas sales	$ 63,874	$ 56,444
Royalties, net of Alberta Royalty Tax Credit	(12,775)	(10,256)
Petroleum and natural gas sales, after royalties	51,099	46,188
Oil and gas hedging costs [note 7]	(10,481)	(7,840)
	40,618	38,348
Expenses		
Operating	9,310	6,912
General and administrative	1,668	1,289
Interest	3,123	3,125
Depletion, depreciation and site restoration	12,987	8,646
	27,088	19,972
Income before taxes	13,530	18,376
Provision for income taxes [note 6]	5,458	7,705
Net income for the year	8,072	10,671
Retained earnings, beginning of year	13,193	2,522
Retained earnings, end of year	$ 21,265	$ 13,193
Net income per share [note 5]		
Basic	$ 0.27	$ 0.39
Diluted	$ 0.26	$ 0.38

See accompanying notes.

Consolidated Statements of Cash Flows

Years ended December 31 *(thousands of dollars, except per share amounts)*	2001	2000
Operating Activities		
Net income for the year	$ 8,072	$ 10,671
Add items not requiring cash:		
Depletion, depreciation and site restoration	12,987	8,646
Future income taxes [note 6]	5,146	7,488
Cash flow from operations	26,205	26,805
Changes in non-cash working capital	4,919	(6,923)
Cash provided by operating activities	31,124	19,882
Financing Activities		
Issue of common shares for cash, net of costs	9,457	5,943
Increase in long-term debt	15,686	41,026
Increase (decrease) in bank indebtedness	(3,660)	3,701
Cash provided by financing activities	21,483	50,670
Investing Activities		
Expenditures on property and equipment	(52,607)	(20,604)
Acquisition of core area properties [note 3]	–	(49,948)
Cash used in investing activities	(52,607)	(70,552)
Cash, beginning and end of year	$ –	$ –
Cash flow from operations per share [note 5]		
Basic	$ 0.87	$ 0.99
Diluted	$ 0.84	$ 0.95

See accompanying notes.

Notes to Consolidated Financial Statements

December 31, 2001 and 2000 *(tabular amounts in thousands of dollars, unless otherwise stated)*

1 DESCRIPTION OF BUSINESS

Thunder Energy Inc. (the "Company") was incorporated under the laws of the Province of Alberta on October 17, 1995. The Company's primary business is the acquisition of, and the exploration for and development and production of crude oil and natural gas in Western Canada.

2 SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries.

The consolidated financial statements, which have been prepared in accordance with Canadian generally accepted accounting principles, have in management's opinion been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

Property and equipment

Petroleum and natural gas properties and gas plants and related facilities

The Company follows the full cost method of accounting whereby all costs associated with the acquisition of and the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in one Canadian cost centre and charged to income as set out below. Such costs include lease acquisition, drilling, equipping, geological and geophysical costs and overhead expenses directly related to exploration and development activities. No indirect general and administrative costs have been capitalized.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion of petroleum and natural gas properties is provided on accumulated costs using the unit of production method based on estimated gross proved petroleum and natural gas reserves, as determined by independent engineers. For purposes of the depletion calculation, proved petroleum and natural gas reserves are converted to a common unit of measure on the basis of one barrel of oil or liquids being equal to six mcf of natural gas. Costs of acquiring and evaluating unproved properties are excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the properties or impairment occurs.

Depreciation of gas plants and related facilities is calculated on a straight-line basis over their estimated useful lives of fifteen years.

The net carrying value of the Company's petroleum and natural gas properties and gas plants and related facilities is limited to an ultimate recoverable amount. This amount is the aggregate of estimated future net revenues from proved reserves and the costs of unproved properties, net of impairment allowances, less future estimated production costs, general and administrative costs, financing costs, site restoration and abandonment costs, and income taxes. Future net revenues are estimated using prices and costs without escalation or discounting, and the income tax and Alberta Royalty Tax Credit legislation in effect at year end.

Office equipment

The Company records office equipment at cost and provides depreciation on the declining balance method at rates varying from 20% to 100% per annum which is designed to amortize the cost of the assets over their estimated useful lives.

Provision for site restoration

Estimated future costs relating to abandonment and site restoration of petroleum and natural gas properties and gas plants and related facilities are provided for over the life of proved reserves on a unit of production basis. The annual provision is accounted for as part of depletion, depreciation and site restoration expense and actual expenditures are charged to the accumulated provision account as incurred. Costs, net of expected recoveries, are estimated based upon current legislation, costs, technology and industry standards.

Measurement uncertainty

The amounts recorded for depletion and depreciation of property and equipment, the provision for site restoration costs and the ceiling test calculation are based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future periods could be significant.

Joint operations

Substantially all of the Company's petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the Company's proportionate interest in such activities.

Flow through shares

A portion of the Company's exploration and development activities is financed through proceeds received from the issue of flow through shares. Under the terms of the flow through share issues, the tax attributes of the related expenditures are renounced to the share subscribers. To recognize the foregone tax benefits to the Company, the carrying value of the shares issued is reduced by the tax effect of the tax benefits renounced to subscribers. The tax effect of the renouncement is recorded when the corresponding exploration and development expenditures are incurred and renounced.

Income taxes

The liability method is used in accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period in which the change occurs.

Financial instruments

In limited circumstances, commodity price derivative instruments are used to reduce the Company's exposure to adverse fluctuations in commodity prices to protect cash flow generated from a major investment financed with long-term debt. Gains and losses relating to commodity swaps that meet hedge criteria are recognized as part of net petroleum and natural gas sales concurrently with the hedged transaction.

Stock based compensation

The Company has a stock based compensation plan, which is described in note 5. No compensation expense is recognized for this plan when stock options are issued to employees. Any consideration paid by employees on the exercise of stock options is credited to share capital.

Per share amounts

The Company utilizes the treasury stock method in the determination of diluted per share amounts. Under this method, the diluted weighted average number of shares is calculated assuming the proceeds that arise from the exercise of outstanding, in the money options are used to purchase common shares of the Company at their average market price for the period.

3 PROPERTY AND EQUIPMENT

	2001		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	$ 124,617	$ 20,599	$ 104,018
Gas plants and related facilities	57,320	8,129	49,191
Office equipment	317	217	100
	$ 182,254	$ 28,945	$ 153,309

	2000		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	$ 92,297	$ 11,308	$ 80,989
Gas plants and related facilities	37,078	4,859	32,219
Office equipment	272	177	95
	$ 129,647	$ 16,344	$ 113,303

At December 31, 2001, costs of $8,489,000 (2000 – $6,985,800) related to unproven properties have been excluded from the depletion calculation. For the year ended December 31, 2001, the Company charged $386,223 (2000 – $203,943) to depletion, depreciation and site restoration expense for future site restoration costs.

In 2000, the Company acquired its partner's 50% joint venture interest in three of its core area petroleum and natural gas properties for $50 million. The acquisition was financed through a public offering of 2,400,000 common shares [note 5c] for net proceeds of $5.7 million and $44 million of bank debt.

4 LONG-TERM DEBT

The Company has an $80 million credit facility consisting of a revolving demand loan with a Canadian chartered bank that bears interest at the bank's prime rate. The Company has pledged all of its assets as collateral for loans under the facility.

At December 31, 2001, the effective interest rate on the debt outstanding was 3.53% (2000 – 7.06%). Interest paid during the years ended December 31, 2001 and 2000 approximates interest expense in each year.

While the credit facility is demand in nature, the bank has stated that it is not its intention to call for repayment before December 31, 2002 provided there is no adverse change in the financial position of the Company. Accordingly, the loan is classified as long term.

5 SHARE CAPITAL

Authorized

Unlimited number of voting common shares with no par value
Unlimited number of non-voting preferred shares issuable in series

Issued

	Number of Shares	$000's
Balance, December 31, 1999	25,743,560	$ 23,775
Issued for cash on private placement (c)	2,400,000	5,740
Issued for cash on exercise of stock options	511,666	414
Balance, December 31, 2000	28,655,226	29,929
Issued for cash on private placements (a)	2,000,000	9,555
Issued for cash on exercise of stock options	208,299	226
Balance, December 31, 2001	30,863,525	$ 39,710

(a) In April 2001, the Company issued 2,000,000 Special Warrants for gross proceeds of $10,000,000. Issue costs totaled $769,000 and have been recorded net of the associated tax benefit of $324,000. The Special Warrants were converted into common shares in June 2001.

(b) In accordance with the terms of its flow through share offerings, and pursuant to certain provisions of the Income Tax Act (Canada), the Company is committed to renounce, for income tax purposes, exploration and development expenditures incurred to holders of its flow through shares. During the year ended December 31, 2000, the Company renounced $3,142,988 of expenditures with a tax effect of $1,402,401 which was recorded as an adjustment to share capital and the future income tax liability.

(c) In June 2000, the Company issued 2,400,000 common shares for gross proceeds of $6,000,000. Issue costs totaled $470,847 and have been recorded net of the associated tax benefit of $210,097.

Stock based compensation

The Company has established a stock option plan whereby options may be granted to the Company's directors, officers and employees for up to 3,071,000 common shares. The exercise price of each option equals the market price of the Company's stock on the date of the grant. An option's maximum term is five years and the options vest equally over three years beginning at the date the option is granted. The following is a continuity of stock options outstanding for which shares have been reserved:

	2001		2000	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Opening	2,275,000	$ 1.99	1,810,000	$ 1.37
Granted	692,000	3.51	980,000	2.51
Exercised	(208,299)	1.09	(511,666)	(0.81)
Cancelled	(33,332)	2.54	(3,334)	(1.85)
Closing	2,725,369	$ 2.44	2,275,000	$ 1.99

The following summarizes information about stock options outstanding at December 31, 2001:

Grant Price	Number Outstanding	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable (Vested)	Weighted-Average Exercise Price (Vested)
$1.08 – $1.60	171,667	2.0	$ 1.32	121,672	$ 1.33
$1.61 – $2.20	1,116,702	1.9	1.79	920,046	1.76
$2.21 – $3.00	890,000	3.7	2.68	253,338	2.69
$3.01 – $3.75	547,000	4.7	3.74	–	–
$1.08 – $3.75	2,725,369	3.1	$ 2.44	1,295,056	$ 1.90

Per share amounts

Per share amounts are calculated using the weighted average number of common shares outstanding during the year of 30,124,060 (2000 – 27,127,449). The diluted per share amounts of 31,342,582 (2000 – 28,314,476) are calculated assuming the exercise of outstanding, in the money options.

6 INCOME TAXES

Income taxes recorded in the consolidated statements of income and retained earnings differ from the tax calculated by applying the combined Canadian corporate federal and provincial income tax rate to income before taxes as follows:

	2001	2000
Computed income tax expense at 42.62% (2000 – 44.62%)	$ 5,766	$ 8,199
Add (deduct) income tax effect of:		
Non-deductible crown charges, net of ARTC	4,243	3,304
Resource allowance	(4,195)	(4,038)
Provincial income tax rate adjustment	(727)	–
Other	59	23
Future income tax expense	5,146	7,488
Large corporation tax expense	312	217
Provision for income taxes	$ 5,458	$ 7,705

The primary temporary differences that give rise to the future income tax liability relate to deductions for tax purposes in respect of property and equipment that exceed depletion and depreciation provided for in the accounts.

Taxes paid approximate large corporation tax expense for each of the years ended December 31, 2001 and 2000.

As at December 31, 2001, the Company has tax pools available for deduction against future income as follows:

	2001	2000
Canadian oil and gas property expense (COGPE)	44,617	41,080
Canadian development expense (CDE)	12,005	8,773
Canadian exploration expense (CEE)	7,831	–
Undepreciated capital cost (UCC)	36,963	25,495
Non-capital losses	–	1,552
Share issue costs	1,573	1,475
Total	102,989	78,375

7 | FINANCIAL INSTRUMENTS

Financial instruments recognized on the balance sheet consist mainly of accounts receivable, bank indebtedness, accounts payable and accrued liabilities and long-term debt. As at December 31, 2001 and 2000, there are no significant differences between the carrying amounts of these instruments on the balance sheet and their estimated fair values.

The Company was a party to certain off balance sheet derivative financial instruments in 2001 and 2000, including crude oil and natural gas swap contracts, fixed price contracts and power contracts. The Company entered into the crude oil and natural gas swap contracts and the fixed price contracts for the purposes of protecting its near term cash flow from operations related to the acquisition of core area properties from the volatility of crude oil and natural gas commodity prices [note 3].

At December 31, 2001, the Company is a party to a power swap contract which fixes the price of 24 megawatt hours ("MWh") of electricity per day at $78.00 per MWh through December 31, 2005. Operating expenses for the year ended December 31, 2001 include losses of $25,800 (2000 – nil) associated with this contract. At December 31, 2001 this contract was out of the money by $0.9 million. This value is based upon the fair market value of the contract at year end and represents the amount the Company would be required to pay to terminate the contract. This instrument has no book value recorded in the consolidated financial statements.

8 | COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the presentation adopted in the current year.

2001 Quarterly Information	Q1	Q2	Q3	Q4	2001
Financial *($ thousands, except where noted)*					
Petroleum and natural gas sales	23,320	18,297	11,284	10,973	63,874
Cash flow from operations	5,021	10,197	5,386	5,601	26,205
Per share – basic *($)*	0.17	0.34	0.18	0.18	0.87
– diluted *($)*	0.17	0.33	0.17	0.17	0.84
Net income	1,265	5,177	1,133	497	8,072
Per share – basic *($)*	0.04	0.17	0.04	0.02	0.27
– diluted *($)*	0.04	0.17	0.03	0.02	0.26
Operations					
Daily production					
Natural gas *(mcf)*	22,398	26,089	25,730	30,155	26,113
Crude oil and NGLs *(bbls)*	1,742	1,458	1,385	1,424	1,501
Prices					
Natural gas *($/mcf)*	9.32	6.12	3.13	3.14	5.20
Crude oil and NGLs *($/bbl)*	28.92	27.90	29.90	16.94	26.03
Wells drilled					
Gross	13.0	13.0	12.0	6.0	44.0
Net	12.6	12.8	10.6	5.4	41.4
Share trading information					
Volume *(thousands)*	4,372	8,147	1,270	2,316	16,105
High *($)*	4.30	5.20	4.25	3.55	5.20
Low *($)*	2.50	3.80	2.60	2.30	2.30
Close *($)*	4.10	4.00	2.99	2.75	2.75

2000 Quarterly Information	Q1	Q2	Q3	Q4	2000
Financial *($ thousands, except where noted)*					
Petroleum and natural gas sales	7,433	11,726	16,002	21,283	56,444
Cash flow from operations	4,200	6,360	7,509	8,736	26,805
Per share – basic *($)*	0.16	0.25	0.27	0.31	0.99
– diluted *($)*	0.15	0.24	0.26	0.30	0.95
Net income	1,663	2,589	3,078	3,341	10,671
Per share – basic *($)*	0.06	0.10	0.11	0.12	0.39
– diluted *($)*	0.06	0.10	0.10	0.12	0.38
Operations					
Daily production					
Natural gas *(mcf)*	15,082	18,743	21,355	21,594	19,206
Crude oil and NGLs *(bbls)*	1,035	1,378	1,639	1,595	1,413
Prices					
Natural gas *($/mcf)*	3.05	4.25	5.27	8.22	5.42
Crude oil and NGLs *($/bbl)*	34.49	35.72	37.46	33.22	35.28
Wells drilled					
Gross	11	3	11	10	35
Net	9.8	2.5	11	10	33.3
Share trading information					
Volume *(thousands)*	887	2,353	2,008	2,049	7,297
High *($)*	1.90	2.75	3.07	2.80	3.07
Low *($)*	1.30	1.45	2.20	2.00	1.30
Close *($)*	1.80	1.60	2.60	2.73	2.73

Quarterly Review

5-Year Review

Financial *Years ended December 31 ($ thousands, except where noted)*	% Change	2001	2000	1999	1998	1997
Petroleum and natural gas sales	13	63,874	56,444	15,431	10,013	5,472
Cash flow from operations	(2)	26,205	26,805	7,785	4,537	2,251
Per share – basic *($)*	(12)	0.87	0.99	0.35	0.28	0.16
– diluted *($)*	(12)	0.84	0.95	0.34	0.26	0.15
Net income	(24)	8,072	10,671	2,437	1,314	393
Per share – basic *($)*	(31)	0.27	0.39	0.11	0.08	0.03
– diluted *($)*	(32)	0.26	0.38	0.11	0.08	0.03
Return on equity *(%)*	(47)	16	30	11	9	6
Capital expenditures	(25)	52,607	70,552	21,891	13,236	19,302
As at December 31						
Working capital deficit	67	3,144	1,885	5,108	3,951	6,792
Long-term debt	30	68,538	52,852	11,825	9,754	6,962
Shareholders' equity	41	60,975	43,122	29,342	16,968	7,548
Total assets	30	160,004	123,159	51,813	33,554	25,326
Common shares outstanding *(thousands)*						
Basic	8	30,864	28,655	25,744	19,279	14,360
Diluted	9	33,589	30,930	27,544	21,744	16,735
Weighted average – basic	11	30,124	27,127	21,966	16,187	13,506
– diluted	11	31,343	28,314	23,131	17,402	14,225
Share price *($)*						
High	69	5.20	3.07	2.65	2.44	3.25
Low	77	2.30	1.30	1.00	1.25	0.90
Close	1	2.75	2.73	2.00	1.60	2.18
Volumes *(thousands)*	120	16,105	7,327	3,313	3,967	10,340

Operations *Years ended December 31*	% Change	2001	2000	1999	1998	1997
Average daily production						
Natural gas *(mcf)*	36	26,113	19,206	9,347	7,748	4,580
Crude oil and NGLs *(bbls)*	6	1,501	1,413	761	853	265
Barrels of oil equivalent *(boe)*	27	5,853	4,614	2,319	2,144	1,028
Average product prices						
Natural gas *($/mcf)*	(4)	5.20	5.42	2.66	2.00	1.98
Crude oil and NGLs *($/bbl)*	(26)	26.03	35.28	22.94	14.57	22.33
Wells drilled						
Gross	26	44.0	35.0	28.0	33.0	36.0
Net	24	41.4	33.3	15.4	16.5	16.0
Success rate *(%)*	4	95	91	93	91	93
As at December 31						
Reserves – proved plus probable						
Natural gas *(bcf)*	11	126.3	114.1	64.2	45.2	37.6
Crude oil and NGLs *(mbbls)*	4	7,650	7,348	3,852	3,548	2,461
Barrels of oil equivalent *(mboe)*	9	28,693	26,365	14,552	11,081	8,728
Net asset value	(14)	169,809	197,058	68,810	47,341	38,613
Per share – basic *($)*	(21)	5.29	6.72	2.58	2.29	2.50
– diluted *($)*	(21)	5.06	6.37	2.50	2.17	2.31

Douglas A. Dafoe, C.A.
President and CEO

Brent T. Kirkby, CMA
Vice President, Finance and CFO

David L. Barlow, P.Geol.
Vice President, Exploration

Terry S. Meek, P.Eng.
Vice President, Engineering

Corporate Information

Directors

James M. Pasieka(1)(2)
Chairman of the Board
Barrister & Solicitor
Heenan Blaikie

Jack Peltier(1)(3)
President
Ipperwash Resources Ltd.

Colin D. Boyer, P.Eng.(1)(2)(3)
President
Birchill Resources Limited

Lauchlan J. Currie(2)(3)
Managing Director
ARC Financial Corporation

Douglas A. Dafoe, C.A.
President and
Chief Executive Officer
Thunder Energy Inc.

David L. Barlow, P.Geol.
Vice President, Exploration
Thunder Energy Inc.

(1) Audit Committee
(2) Compensation Committee
(3) Reserve Evaluation Committee

Corporate Secretary

Felicia B. Bortolussi
Barrister & Solicitor
Heenan Blaikie

Independent Engineers

Sproule Associates Limited
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Legal Counsel

Heenan Blaikie
Calgary, Alberta

Bankers

Bank of Montreal
Calgary, Alberta

Transfer Agent & Registrar

Valiant Corporate Trust Company
Calgary, Alberta

Stock Listing

The Toronto Stock Exchange
Symbol: THY

Abbreviations

bbl(s) ....barrel(s)
mbbls ....thousand barrels
mmbbls ....million barrels
mcf ....thousand cubic feet
mmcf ....million cubic feet
bcf ....billion cubic feet
boe ....barrel of oil equivalent (6 mcf = 1 bbl)
mboe ....thousand boe
mmcfe ....million cubic feet equivalent (1 bbl = 6 mcf)
/d ....per day
ARTC................Alberta Royalty Tax Credit
NGLs ....natural gas liquids
WTI..................West Texas Intermediate
GJ ....gigajoule (1.054 mcf)
btu....................British thermal units
m ....metres

Notice of Annual Meeting

Shareholders and guests are invited to attend the Annual Meeting to be held on Wednesday, May 29, 2002 at 3:00 p.m. in the McMurray Room of The Calgary Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta.

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THUNDER ENERGY INC. 2001

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